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Effect of Corrosion on Heat Transfer through Boiler Tube and Estimating Overheating

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Abstract

The product of corrosion in the feed water system transported into the boiler and gets deposited on the internal surface of waterwall tubes. Proper treatment of boiler feedwater effectively protects against corrosion of feedwater heaters, economizers, and deaerators. It leads to overheating and on-load corrosion and ultimately tube failure.. Heat is transferred through a thin layer of superheated liquid on a metal surface, the temperature gradient rising to about 10oC as the heat transfer rate increases and the boiling point of the liquid is approached Failure of boiler tubes by corrosion attack has been a familiar phenomenon in power plants resulting in unscheduled plant shut down. The effects of scales and/or corrosion products in reducing thermal conduction leading to higher temperatures in the underlying metal can lead to other modes of failure. Boiler wall tubes are joined to the water drum by expanding and flaring the tubes in the drum plate hole. It seems during fabrication the tube ends were not stress relieved and when these tubes with enough residual stresses came into contact with corrosive condensate, a synergic interaction of tensile stress and a corrodent occurred and resulted into stress corrosion cracking (SCC). There are two principal causes that govern SCC in the boiler environment. First, the metal in the affected region must be stressed to a sufficiently higher level. Second, concentration of a specific corrodent at the stressed metal site must occur. Both the above mentioned factors are observed to play a role ion SCC of the tube.

This paper will discuss effect of corrosion on heat transfer rate with varying corrosion condition of boiler tubes and to overcome this, how much extra heat supplied as overheating is also concern of this paper.

Keywords: Feed water system, Corrosion, Water wall, Overheating, stress corrosion cracking

1. Introduction

The failure of industrial boilers has been a prominent feature in fossil fuel fired power plants.

Many corrosion problems occur in the hottest areas of the boiler-the water wall, screen, and superheater tubes. Other common problem areas include deaerators, feedwater heaters, and economizers. Methods of corrosion control vary depending upon the type of corrosion encountered. The most common causes of corrosion are dissolved gases (primarily oxygen and carbon dioxide), under-deposit attack, low pH, and attack of areas weakened by mechanical stress, leading to stress and fatigue cracking.

These conditions may be controlled through the following procedures:

- maintenance of proper pH and alkalinity levels
- control of oxygen and boiler feedwater contamination
- reduction of mechanical stresses
- operation within design specifications, especially for temperature and pressure
- proper precautions during start-up and shutdown
- effective monitoring and control

Long term overheating tube failures are due to operating metal temperature of the boiler tubes going above the allowable limit. These types of failure are seen in steam cooled tubes like superheaters and reheaters and in water cooled tubes of waterwalls.

Boilers used for industrial steam generation and power generation have kilometers of tubes that carry water and steam in circulation system and superheaters, respectively. These tubes are of various sizes and thicknesses depending upon the pressure and the mid-wall metal temperature. The tubes selected are boiler quality tubes manufactured under various standards like ASME, BS, DIN, JIS, etc. While selecting the tube there is a requirement to select the correct material for withstanding the metal temperature. This will depend upon the location where the heat transfer surface is located. Normally the water cooled areas like economizer and waterwalls are made of carbon steel of boiler quality. Superheaters and reheaters will have combination of low alloy tubes to stainless steel tubes selected to withstand the metal temperature.

2. Literature Review

Boiler tube failures are a major cause of forced outages in the power production industry. As a means for improving asset availability, many power generation executives are making significant capital investments in new tube bundles. While full tube wall thickness may reduce the frequency of leaks, varying operating conditions can accelerate deterioration of the new tubes. New tubes made of commonly accepted materials, including carbon and stainless steels, are not necessarily designed to withstand the current operating variables of today’s power generation industry. Reduced reliability due to corrosion attack is one of the main problems in boiler systems costing billions of dollars per year.

Pre-boiler corrosion – Metal transport to boiler from external equipments.
Pre-boiler corrosion will include corrosion in all steam – condensate network and also in boiler feed water section. Therefore corrosion in all areas that at the end will impact in higher iron or copper concentrations arriving to boiler will be included in this definition. Pre-boiler corrosion defines the area where the phenomenon takes place, but it may includes different corrosion mechanism like:

- Oxygen corrosion
- pH related metal protective layer stability
- Ammonia – Copper alloys associated corrosion
- Galvanic corrosion
- Erosion-Corrosion and Flow Accelerated Corrosion

Pre-boiler Oxygen Corrosion
In the presence of oxygen, the corrosion process described above is modified. Dissolved oxygen replaces hydrogen ions in the reduction reaction. This reaction occurs more readily than the direct reaction between iron and protons. Oxygen usually enters the system through water make up or direct absorption of air in condensate tanks, or in vacuum zones in complex condensate networks, like it is the case in Refineries and Petrochemical plants

pH related metal protective layer stability
The stability of the passivating iron oxide layer is critically dependent on pH and temperature. Any contaminants in the system that cause the pH to decrease cause dissolution of the oxide layer and increased corrosion. Carbon dioxide (CO2) is the primary cause of decreased condensate pH. Carbon dioxide enters the system with air leaking in condensate vacuum areas, in atmospheric condensate tanks or from decomposition of feedwater alkalinity. The latter should not be a problem in refinery and petrochemical industry using demineralized makeup water. Low pH causes a generalized loss of metal rather than the localized pitting caused by oxygen corrosion.

$$CO_2 + H2O \rightarrow H_2CO_3$$

$$H_2CO_3 \rightarrow H^+ + HCO_3^-$$

$$Fe + 2H^+ \rightarrow Fe^{2+} + H_2$$

3. Ammonia – Copper alloys associated corrosion
Corrosion on copper or copper alloys is influenced by pH and also oxygen and ammonia concentrations. The anode semi reaction is as follows:

$$Cu + 2\,NH_3 \rightarrow Cu(NH_3)_2^+ + e^-$$

The oxygen will then oxidize the bi-ammonia group to tetra-ammonia, still with ammonia present:

$$Cu(NH_3)_2^{+} + ½\, O_2 + H_2O + 4\, NH_3 \rightarrow 2\; Cu(NH_3)_4^{+2} + 2\, OH^-$$

4. Pre-boiler Galvanic Corrosion

Galvanic corrosion occurs when a metal or alloy is electrically coupled to a different metal or alloy. The most common galvanic corrosion in refinery and petrochemical industry is by contact of dissimilar metals, as iron and copper.

5. Erosion-Corrosion and Flow accelerated corrosion

Erosion is a type of corrosion phenomena affected by several factors:

- Velocity
- Geometry
- Metallurgy
- Water Chemistry

Velocity is frequently the major factor in erosion – corrosion. We may have liquid impingement corrosion due to high velocity in certain steam or condensate areas Even in the absence of oxygen iron corrodes in water. Iron surface acts as a car battery, the metal surface is divided into microscopic anodes (+) and cathodes (-). Iron acts as an anode so that it is oxidized giving its electrons to the cathode. Single-phase FAC occurs where all of the water is in the liquid phase – there is no vapor or steam generation in that pipe or tube section. The general appearance of the attack can be described as an orange peel, bubble-like texture.

Carbon steel components with water velocities greater than 2.4 – 3 m/s. are particularly susceptible to FAC attack. Also the rate of FAC attack is at a maximum around 130 – 150 ºC for single-phase flow and 150 – 200 ºC for two-phase flow.

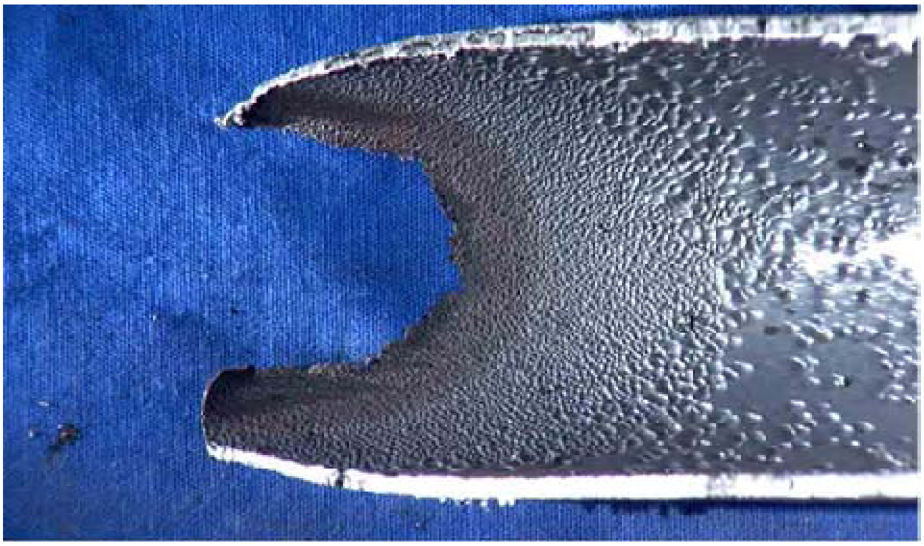

Fig.1 Flow Accelerated Corrosion

Sulfur-Induced Corrosion

Sulfur typically is found as sodium sulfate in fuel ash. At high temperature it dissociates according to the following reaction

$$Na_2SO_4 \rightarrow Na_2O + SO_3$$

The reaction products will alter the basicity of the molten ash deposits. Sulfur reacts with sodium in the melt altering the concentration of Na2O, and thereby changing the corrosion rates. The melting of deposits depends on the Na + S/V ratio and it ranges from 480-900 oC. As the intergranular corrosion of the fireside surface of the tubes increases the mechanical properties of the tube metal deteriorates. Under these circumstances if the temperature and pressure of the tube elevate abnormally due to some reason, the tube will burst.

Stress Enhanced Corrosion

In the case of tube A it appears that the weldment was not stress relieved. When corrosive conditions are prevalent, the current flow between the anodic and cathodic half cells (stressed and unstressed regions respectively) is greatly enhanced. The welding stresses of tube, therefore, might have enhanced the growth of the fissures caused by sulfur induced corrosion and this resulted into the cracking of the tube at the weldment.

Long Term Overheating

The strength of carbon steel remain nearly constant up to about 454^0C. Above this temperature, steel begins to loose its strength rapidly. If the tube metal temperate is gradually increased beyond this temperature, it will plastically deform and then rupture. The approximate time to rupture is a function of the hoop stress (related to internal pressure and tube dimension) and the temperature. The localized nature of the overheating is a consequence of the fact that deposits do not form uniformly along the time. The deposits, occur in locations of high heat flux. Deposits may also favor areas here physical “drop out” of suspended solids is more likely, such as weld backing rings or sloped tubes. These deposits insulate the metal from the cooling effects of the water, resulting in reduced heat transfer into the water and increased metal temperatures.

Stress corrosion cracking (SCC)

Stress corrosion cracking (SCC) is the growth of cracks in a corrosive environment. It can lead to unexpected sudden failure of normally ductile metals subjected to a tensile stress, especially at elevated temperature in the case of metals. SCC is highly chemically specific in that certain alloys are likely to undergo SCC only when exposed to a small number of chemical environments. The chemical environment that causes SCC for a given alloy is often one which is only mildly corrosive to the metal otherwise. Hence, metal parts with severe SCC can appear bright and shiny, while being filled with microscopic cracks. This factor makes it common for SCC to go undetected prior to failure. SCC often progresses rapidly, and is more common among alloys than pure metals. The specific environment is of crucial importance, and only very small concentrations of certain highly active chemicals are needed to produce catastrophic cracking, often leading to devastating and unexpected failure.

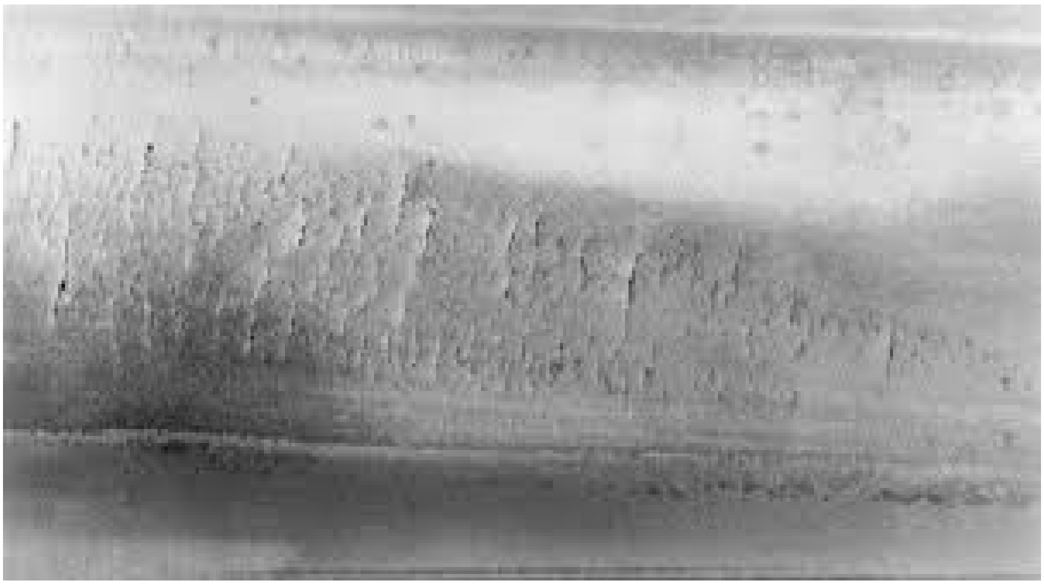

Fig.2 Stress corrosion cracking in pipe[3]

Fig.3 Stress corrosion cracking in material

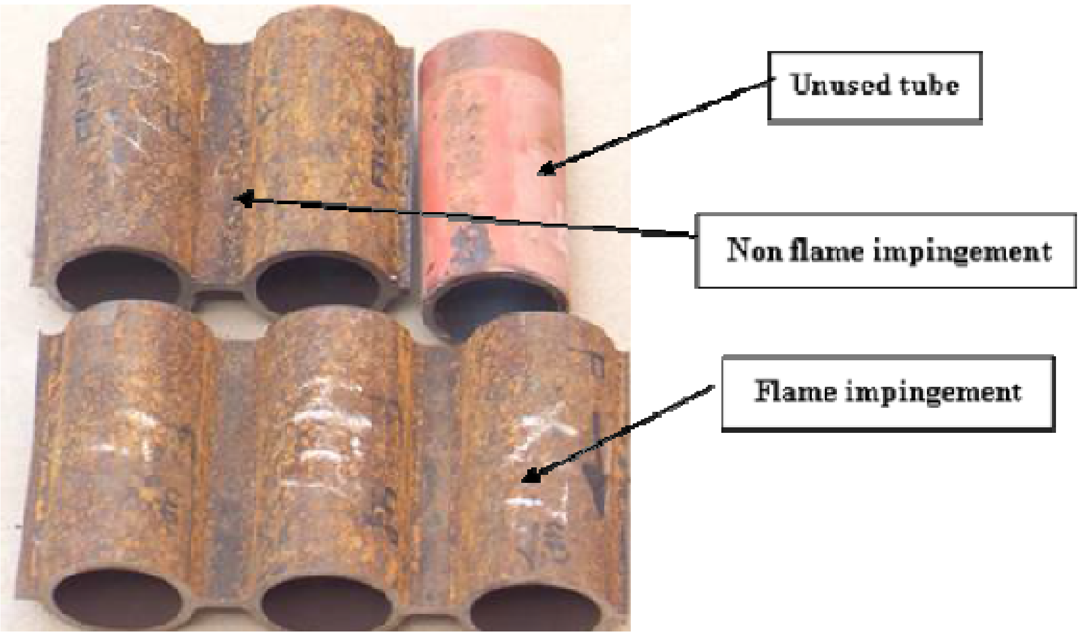

Fig.4 Photograph of fire side water wall tubes in as received conditions

3. Research Methodology

Stress corrosion cracking (SCC) is a form of localized damage that refers to cracking under the combined influence of tensile stress and a corrosive environment. The macroscopic fracture appearance tends to be of the "brittle" type, even if the metal/alloy is of a mechanically ductile variety. Stresses that can contribute to SCC include the applied, residual and thermal varieties, and also those generated by the build-up of corrosion products. Welding, heat treating, fitting and forming operations can produce significant residual stress levels, in some cases approaching the yield strength (often surprising the unsuspecting)

A boiler tube cracking failure from caustic embrittlement corrosion in boilers or oil ash corrosion can be found with boiler tube testing and failure anaylsis. Tube failure analysis and tube testing is well suited for heat exchangers like steam turbine condensers or shell and tube heat exchangers. Heat exchangers of all sizes generally have very-expensive tubes, so replacing the tubing will reach senior decision makers in your facility.

Failure mechanisms are not always clearly identified, then boiler tube failure analysis and testing may be needed. AIS Metallurgical Testing hasyears of experience with boiler tube failures including economiser tube failures, overheated steam drums and water drums (mud drums) as well as boiler headers, superheater tubes and economizer tubes.

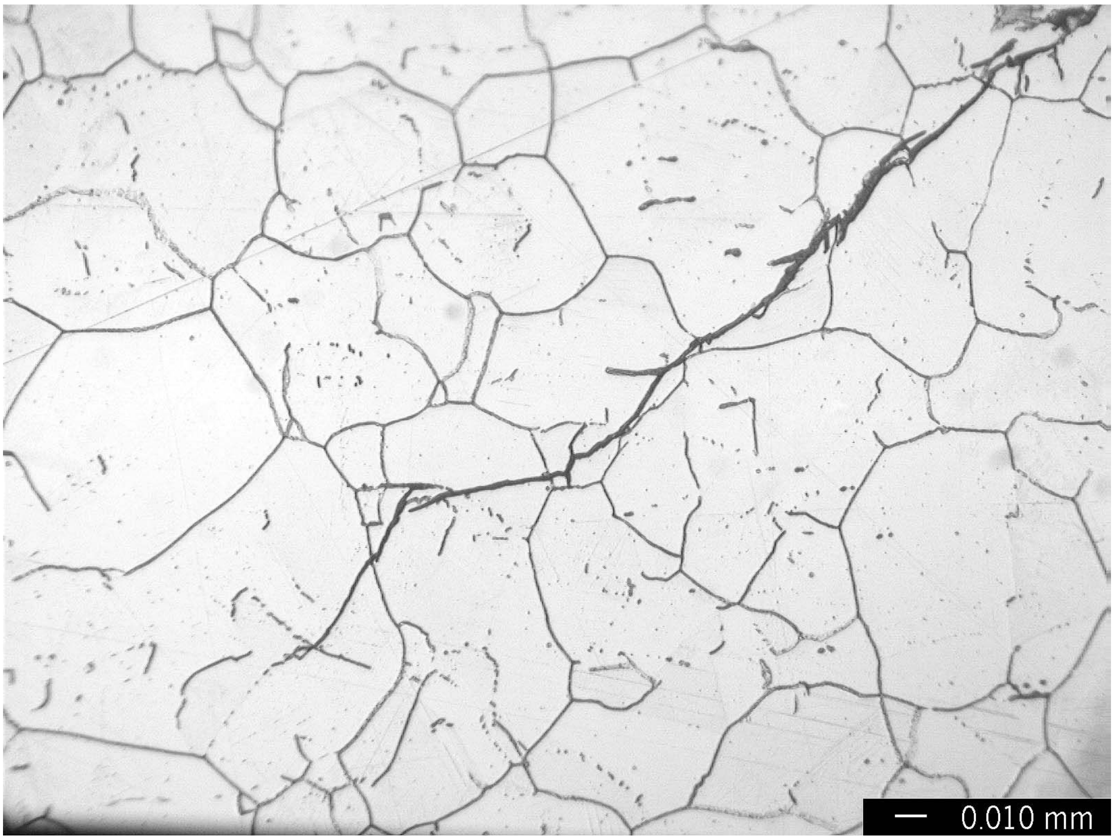

Fig. 5 ***boiler tube testing and failure anaylsis***

Effective corrosion control monitoring is essential to ensure boiler reliability. A well planned monitoring program should include the following:-

- proper sampling and monitoring at critical points in the system.
- completely representative sampling.
- use of correct test procedures.
- checking of test results against established limits.
- A plan of action to be carried out promptly when test results are not within established limits.
- A contingency plan for major upset conditions.
- A quality improvement system and assessment of results based on testing and inspections.

4. Results

- Oxygen corrosion in boiler feedwater systems can occur during start-up and shutdown and while the boiler system is on standby or in storage, if proper procedures are not followed. Systems must be stored properly to prevent corrosion damage, which can occur in a matter of hours in the absence of proper lay-up procedures. Both the water/steam side and the fireside are subject to downtime corrosion and must be protected.

- Corrosion also occurs in boiler feedwater and condensate systems. Corrosion products generated both in the preboiler section and the boiler may deposit on critical heat transfer surfaces of the boiler during operation and increase the potential for localized corrosion or overheating.
- The degree and speed of surface corrosion depend on the condition of the metal. If a boiler contains a light surface coating of boiler sludge, surfaces are less likely to be attacked because they are not fully exposed to oxygen-laden water. Experience has indicated that with the improved cleanliness of internal boiler surfaces, more attention must be given to protection from oxygen attack during storage. Boilers that are idle even for short time periods (e.g., weekends) are susceptible to attack.

5. Conclusions

- Presence of sulfur in the oil ash deposited on the fireside surfaces of the tube appears to be the main cause of the failure of the boiler tubes.
- The mode of failure is intergranular corrosion attack induced by molten ash.
- deposits when the tube metal temperature was raised above normal working temperature, i.e., 480 ^{0}C.
- Thinning of the tube walls is due to localized deposits and overheating problem.
- The oxidation rates of iron and steel in 0, 01 n NaOH and LiOH can be described with a logarithmic equation, based on a mutual pore blocking mechanism.
- Formation of loose oxide in weakly alkaline solutions. This oxide breaks off from the samples during the exposure time.
- Corrosive condensate formed by the condensation of leaked out steam from superheater tubes, initiated SCC of wall tubes fixed in the water drum.

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